CANMET

Canada Centre for Mineral and Energy Technology

Centre canadien de la technologie des minéraux et de l'énergie

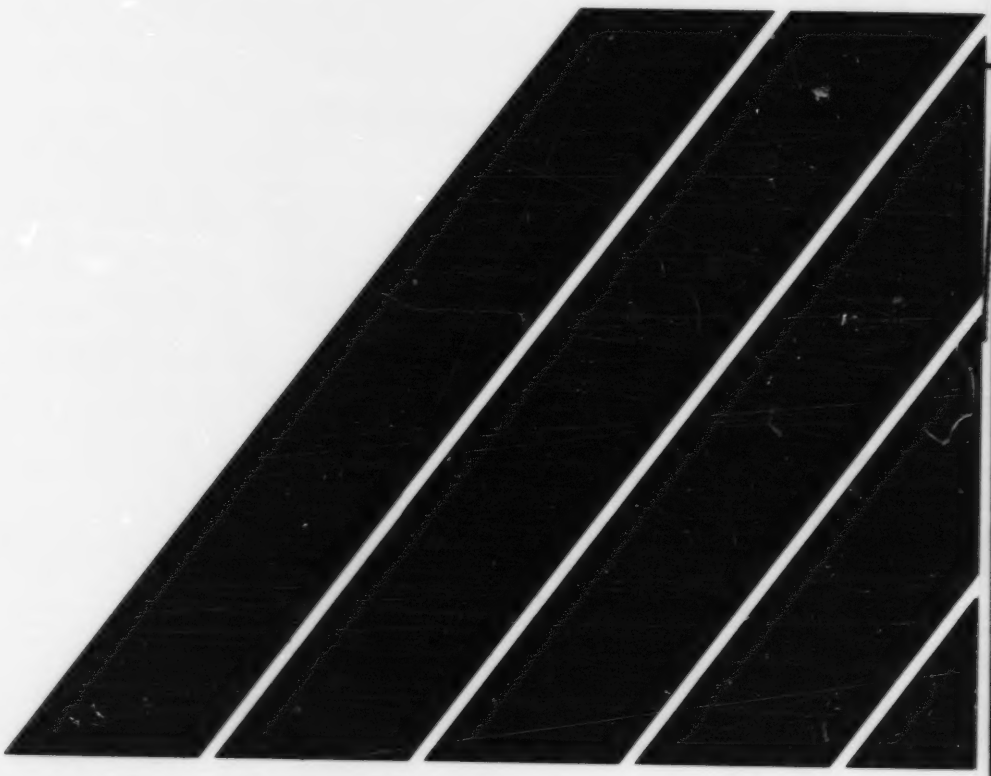
Energy Research Laboratories

Laboratoires de recherche sur l'énergie

RESULTS OF THE FIBEC TEST PROGRAM AT CANADIAN FORCES BASE ST. HUBERT

November 1990

F.D. Friedrich* and V.V. Razbin**



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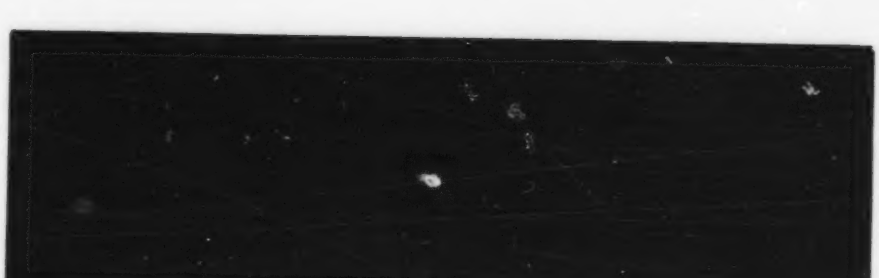

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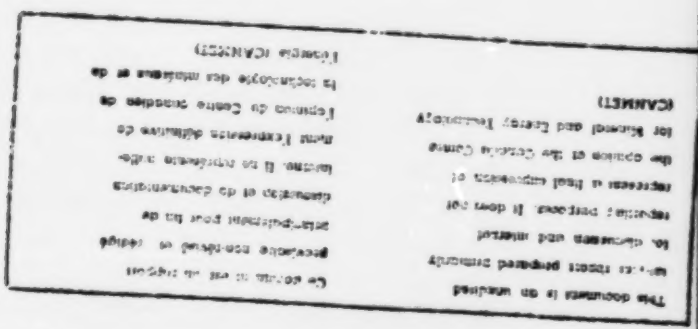

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ABSTRACT

Results of the FIBEC Test Program at Canadian Forces Base St. Hubert, Nov. 1990

F. D. Friedrich and V. V. Razbin

As part of the national management plan for NO_x control, Environment Canada has drafted emissions regulations for industrial boilers, based on best available technology economically achievable. National Defence Canada, as a major boiler owner, has undertaken to demonstrate low-NO_x burners in two plants. One is fuelled by natural gas with No. 2 fuel oil backup and one is fuelled by Bunker "C" oil with No. 2 oil backup.

This report describes the results of combustion tests on the first demonstration - a boiler at CFB St. Hubert which has been retrofitted with a dual-fuel (natural gas and No. 2 fuel oil) burner employing flue gas recirculation (FGR). Tests were conducted with both fuels with and without flue gas recirculation over the load range of the boiler. Both efficiency and emissions were measured.

It was found that FGR reduces NO_x by 50% when firing natural gas, and 20 to 25% when firing No. 2 fuel oil. With natural gas , NO_x emissions were within the limits of the draft regulations with FGR but exceeded limits without FGR. With No. 2 oil, NO_x emissions were within the draft regulations only at low loads; below 40 % Maximum Capacity Rating (MCR) with FGR, below 30% MCR without FGR. CO emissions were well below the limit for both fuels, but SO_2 emissions were several times the limit when firing No. 2 fuel oil.

Résumé

Résultats du programme FIBEC d'essais entrepris à la base des Forces Armées Canadiennes, St. Hubert, Nov. 1990

F.D. Friedrich et V.V. Razbin

"Environnement Canada", a ébauché un règlement sur les émanations de NO_x des chaudières industrielles. Cette ébauche est basée sur la meilleure technologie réalisable compte tenu du prix. Le Ministère de la Défense Nationale, propriétaire de nombreures chaudières, a entrepris une démonstration de brûleurs à faibles émanations de NO_x à deux endroits. Un des deux est alimenté par le gaz naturel avec l'huile "No. 2" en réserve tandis que l'autre est alimenté par "Bunker C" avec l'huile "No. 2" en réserve.

Le rapport décrit les résultats d'essai de combustion pour le premier cas de BFC St-Hubert, le brûleur de la chaudière a été remplacé par un autre à deux carburants (gaz naturel et huila "No. 2"), utilisant un recyclage des gaz de combustion (RGC).Des essais ont été entrepris avec les deux carburants, avec et sans recyclage des gaz et dans l'intervalle dé bits de carburant. L'efficacité et les émanations ont été mesurées.

Pour le cas de recyclage (FRG), nous avons trouvé une réduction des NO_x de 50% avec le gaz naturel comme carburant et de 20-25% avec l'huile "No. 2". Pour le gaz naturel, les émanations de NO_x étaient conformes aux normes prescrites par les règlements proposés si le recyclage est utilisé; par contre sans recyclage les émanations de NO_x dépassaient les normes. Avec l'huile No. 2, les émanations de NO_x étaient conformes aux normes prescrites par les règlements proposés mais seulement à capacité minimale c'est dire en dessous de 30% de la capacité maximale de la chaudière sous recyclage. Les émanations de CO étaient nettement plus faibles que le seuil pour les deux carburants, mais les émanations en SO_2 ont dépasse le seuil pour l'huile "No. 2".

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INTRODUCTION

Combustion source emissions of nitrogen oxides are viewed as a significant air pollution problem in Canada because they contribute to both acid rain and ground-level ozone. Accordingly, the Canadian Council of Ministers of the Environment has requested Environment Canada to develop a management plan for NO_x control. Furthermore, as a signatory to the international protocol for NO_x control, initiated by the United Nations Economic Commission for Europe, Canada is required to develop emission standards for combustion sources based on "best available technology economically achievable" to reduce by 1994 NO_x emissions to the 1987 level and to maintain them there.

Industrial boilers are believed to account for about 40% or 278,000 t/a of all stationary sources of NO_x emissions in Canada. Although the total inventory of federally-owned boilers of industrial size is believed to emit only a fraction of 1% of this figure (1100 t/a) it nonetheless comprises a large number of boilers, about 173, at 70 sites. Also, since emissions from federally-owned boilers fall under the jurisdiction of Environment Canada, they were deemed to be an appropriate group for which to develop new regulations. These regulation are expected to be adopted by provincial agencies especially implemented for all industrial boilers.

New emission standards are being developed by the Federal Industrial Boiler Emission Control (FIBEC) Program. Through a task force involving burner and boiler manufacturers and federal departments which own boilers, Environment Canada has attempted to determine the minimum emissions achievable by using the best technology that is economic and presently available for each of the common fossil fuels. Regulations have been drafted and are summarized in Appendix I. The draft regulations have been forwarded to the Privy Council Office and are expected to be published in Canada Gazette 1 in 1991.

National Defence Canada, as a major boiler owner and therefore a major stakeholder in the FIBEC program, has undertaken the demonstration of low NO_x combustion technologies in two of its heating plants; CFB St. Hubert near Montreal and CFB Dockyard, Halifax. The St. Hubert plant's main fuel is natural gas with backup No. 2 fuel oil. The Dockyard plant's main fuel is No. 6 (Bunker C) with backup No. 2 fuel oil. One boiler in each plant has been retrofitted with a state-of-the-art burner employing flue gas recirculation (FGR) to reduce NO_x emissions.

This report describes tests on the retrofitted boiler at CFB St. Hubert conducted by the Combustion and Carbonization Research Laboratory, Energy Research Laboratories, CANMET, as part of Energy, Mines and Resources Canada's contribution to the FIBEC program. Tests were performed with both fuels at three boiler loads to evaluate the effect of FGR on boiler efficiency and NO_x emissions.

DESCRIPTION OF PLANT

The central heating plant at CFB St. Hubert was built about 1950 as a coal-fired plant having four identical Foster Wheeler Type SA boilers equipped with spreader-fired dump grates. Each boiler is rated at 25000 lb/h at 125 psi (11340 kg/h at 861 kPa), dry and saturated steam. The coal-burning equipment was removed some years ago and the boilers were retrofitted with dual-fuel burners for natural gas and No. 2 fuel oil, one burner per boiler.

Under the FIBEC program, the burner in Boiler No. 4 was replaced with a new burner which was modified to incorporate flue gas recirculation. The new burner was manufactured by Weishaupt GmbH of Germany. Identified as Type RGL70/2-A, version ZM, it has a capacity of 3.4 to 37 million Btu/h (2.19 to 23.9 MJ/s). It fires either natural gas or No. 2 fuel oil. The FRG system is powered by a 15 hp blower, drawing from the boiler breeching just upstream of the induced draft fan, and delivering the flue gas to the windbox on the front of the boiler.

The automatic control system is essentially a Bailey pneumatic system which was installed when the plant was built, with such modifications as were required by the fuel conversion. However, the new burner has its own management system, interfaced with a demand signal from the Bailey system. There is no continuous monitoring of any flue gas component or flue gas temperature, although steam and feedwater parameters are recorded.

TEST PROGRAM

OBJECTIVES

The primary objective was to measure the NO_x and SO_2 emissions from the boiler using both fuels over the load range with the flue gas recirculation (FGR) system. Secondary objectives were to determine the boiler efficiency and the effect of FGR on emissions and on boiler efficiency.

INSTRUMENTATION

Flue gas was continuously analyzed for O_2, CO_2, CO, NO_x and SO_2 by means of an instrument package provided by the Combustion and Carbonization Research Laboratory (CCRL). This well-proven system comprises, besides the analyzers, a stainless-sinter stack probe with a heated line and a sample conditioning unit. The system extracts the sample from the stack, removes the moisture, which otherwise would contaminate the analyzer cells, and delivers dry flue gas at constant pressure, temperature and flow rate to the analyzers. The principle of operation, make and model of the analyzers are as follows:

O_2	Paramagnetic	Beckman Model 755
CO_2	Infrared	Horiba Model PIR 2000
CO	Infrared	Horiba Model PIR 2000
SO_2	Ultraviolet	Western Research Model 721A
NO_x	Chemiluminescent	Thermo Electron Model 10

The analyzers were calibrated usually at the beginning and end of each test by means of bottled span and zero gases. However, for the O_2 analyzer the span setting was obtained by using ambient air.

Combustion air temperature was obtained by installing a chrome-alumel thermocouple just below the air control damper at the bottom of the burner. Flue gas temperature was monitored by three chrome-alumel thermocouples attached to the gas sample probe. One was located near the centreline of the breeching; the others were located 20 to 40 cm from the edge. The average flue gas temperature was calculated by assigning a weight of 2 to the centreline temperature, and weights of 1 each to the outer temperatures.

Thermal output of the boiler was determined from the steam flow meter and integrator on the control panel. The appropriate corrections were made for pressure. When firing natural gas, fuel input measurements were obtained from the integrating meter on the control panel, and corrected for temperature as measured periodically by applying a surface thermocouple to the gas pipe into the burner. When firing No. 2 oil, fuel input measurement involves one integrating meter on the supply line to the burner, and another on the return line. The reading from the latter must be subtracted from that of the former to determine the net oil flow through the burner. However, the return flow meter has a bypass line which the burner manufacturer recommends closing for only short periods to avoid potential blockage problems which could damage the burner. Attempts to measure oil consumption were therefore abandoned as being too inaccurate to justify the effort.

TEST CONDITIONS

Typically tests were carried out under four load conditions approximating minimum fire and 30, 65 and 100% of maximum capacity rating (MCR). To achieve a given load, fuel input was set manually while the excess air level was determined by the automatic controls. Tests with FGR were 2h except for the test using No. 2 fuel oil at minimum fire. Tests without FGR were for shorter periods. A summary of conditions for each test follows:

Test No. 1
Natural Gas with FGR, minimum fire
Duration: 2 h (Nov. 19, 1430-1630 h)
The boiler had been stable at this fuel input for several hours prior to the start of the test. The flame was symmetrical and very transparent blue with some orange tips. Burner ports were clearly visible from the observation ports in the rear furnace wall. The furnace was dimly lit.

Test No. 2
Natural gas with FGR, 30% load
Duration: 2 h (Nov. 19, 2015-2215 h)
The flame was transparent blue with no yellow tails. The burner was clearly visible and the furnace refractory was uniformly orange-red.

Test No. 3

Natural Gas with FGR, 65% load

Duration: 2 h (Nov. 20, 0900-1100 h)

The boiler was held at this load from 0730 h. The flame was transparent blue with no visible tails. The burner was clearly visible and the furnace refractory was uniformly bright orange. At this load the boiler was supplying total plant demand, hence there were fluctuations in steam pressure.

Test No. 4

Natural gas with FGR, full load

Duration: 2 h (Nov. 20, 1300-1500 h)

The flame was invisible except for some blue tongues in the throat of the burner, that was clearly visible from the rear of the furnace. The furnace refractory was a very bright orange. Load was maintained by venting some steam to atmosphere.

Test No. 5

No. 2 fuel oil with FGR, full load

Duration: 2 h (Nov. 20, 1630-1830 h)

The boiler was held at this load since the end of test No. 4 at 1500 h, except for a brief shutdown of 10 min. to switch fuels. Flame conditions were excellent: symmetrical, bright yellow with very clean edges and no sparklers (individual oil droplets burning beyond the flame envelope). The flame was fairly narrow. Part of the burner quarl was visible from the rear of the furnace. The furnace was very brightly lit, therefore it was difficult to determine the colour of the refractory. Load was maintained by venting steam to atmosphere.

Test No. 6

No. 2 fuel oil with FGR, 65% load

Duration: 2 h (Nov. 20, 2015-2215 h)

The boiler was held at this load for about 1.5 h prior to the start of test. The flame was symmetrical, very bright yellow with clean edges and no sparklers. The furnace refractory was bright and clearly visible. Some steam was being vented to help maintain uniform header pressure.

Test No. 7

No. 2 fuel oil with FGR, 30% load

Duration: 2 h (Nov. 21, 0900-1100 h)

The boiler had been at this load for more than 1 h prior to the start of test. The flame was symmetrical, only about 60 or 70 cm in diameter and 2 to 3 m long. It was very bright yellow in colour with clean edges and no sparklers.

The furnace was brightly illuminated and most of the burner was visible from the rear observation ports.

Test No. 8

No. 2 fuel oil with FGR, minimum fire

Duration: 30 min (Nov. 21, 1130-1200 h)

This test was done to establish the turndown ratio, hence the test duration was not important. The flame was bright yellow with somewhat ragged but clean edges and no sparklers. The flame was 60 cm in diameter and less than 2 m long.

Test No. 9

No. 2 fuel oil without FGR, 30% load

Duration: 1 h (Nov. 21, 1300-1400 h)

The flame was essentially the same as that with FGR except a little darker.

Test No. 10

No. 2 fuel oil without FGR, minimum fire

Duration: 1 h (Nov. 21, 1430-1530 h)

The flame was somewhat uneven; bright yellow and clean on the left side of the furnace (as viewed from the rear); darker yellow and smoky on the right side. However, the smoke visible in the furnace was not reflected in the CO measurements or in visible stack emission. The flame was small; 50 to 60 cm in diameter and less than 2 m long.

Test No. 11

No. 2 fuel oil without FGR, 65% load

Duration: 1 h (Nov. 21, 1600-1700 h)

The flame was bright yellow and clean but substantially asymmetrical. The burner and quarl were clearly visible from the left observation port in the rear wall, but not from the right port. Also, the flame was somewhat darker in colour on the right side (as viewed from the rear).

Test No. 12

No. 2 fuel oil without FGR, full load

Duration: 1 h (Nov. 21, 1730-1830 h)

The flame was very bright yellow and clean. It was much more symmetrical than at lower firing rates but some bias to the right side, as viewed from the rear, was still evident.

Test No. 13
Natural Gas without FGR, minimum fire and 30% load
Duration: 45 min. (Nov. 21, 2030-2115 h)
Adjusting the burner to achieve a satisfactory flame without FGR resulted in a minimum fire condition that was close to 30% load. The flame was fairly bushy, nearly 2 m in diameter, and lazy with large yellow tips. It appeared to be somewhat darker on the right side as viewed from the rear.

Test No. 14
Natural gas without FGR, 65% load
Duration: 1 h (Nov. 21, 2215-2315 h)
The flame was essentially transparent, making it impossible to judge size or symmetry. A small amount of blue was visible in the furnace throat, and there were some yellow tips near the back end of the furnace. Furnace refractory was bright orange.

Test No. 15
Natural gas without FGR, full load
Duration: 1 h (Nov. 22, 0930-1030 h)
This condition was maintained for 1 h prior to the start of the test. The flame was invisible except for some transparent blue in the burner throat. The furnace refractory was a uniform yellow-orange.

MEASUREMENTS AND CALCULATIONS

Electronic datalogging of flue gas analysis and thermocouple temperatures was unavailable so these values were recorded manually every 15 min. as were essential data from the boiler control panel and the burner. For each test, average values were computed and used to calculate boiler efficiency and emissions. The integrating meters for steam flow and natural gas flow were read at the start and end of each test.

Boiler efficiencies were calculated using the method specified in the "ASME Test Form for Abbreviated Efficiency Test, PTC 4.1-a (1964)". For natural gas firing, Tests 1 to 4, efficiencies were calculated using both the direct and indirect methods. For No. 2 oil firing, only the indirect method was used, since it was not possible to get an accurate measure of oil flow for the direct method. Radiation and convection losses from the boiler were estimated using the well-known "Radiation and Convection Heat Loss Chart" published by the American Boiler Manufacturers Association. From this was derived Fig. 1, which shows the relationship between load and radiation and convection

losses for boilers of the type and size of those at CFB St. Hubert.

In the raw data tables, (Tables 2 and 4), emissions are recorded as measured, i.e., ppm by volume in the actual flue gas. Subsequently they are reported on the standardized basis of 3% O_2 in the flue gas, and nanogram per Joule (ng/J) of energy input as required by the proposed standard. The requisite calculations are carried out using the formulae specified by Environment Canada.

RESULTS AND DISCUSSION

FUEL ANALYSES

Gaz Metropolitain routinely provides to the plant data on the properties of the natural gas supplied. Thus an analysis dated Nov. 2, 1990, was considered as representative of the natural gas burned during the tests. For No. 2 fuel oil, a sample was taken during the tests and subsequently analyzed at the Energy Research Laboratories. Data for both fuels are given in Table 1.

RESULTS WITH NATURAL GAS TESTS

Table 2 gives averaged data for the tests using natural gas firing. Data derived from Table 2 including boiler efficiency and emissions are given in Table 3 and Fig. 2 to 4.

The values obtained by the direct method for boiler efficiency in tests 2 to 4, widely disagree with those obtained by the indirect method, and with the efficiency range that can be expected from boilers of this type. With careful determination of flue gas analysis and flue gas temperatures, results obtained by the indirect method are accurate within 0.5%. Therefore the direct method values should be discarded. The error is probably due to inaccurate metering of natural gas or steam. Only the efficiencies obtained by the indirect method are plotted in Fig. 2, which shows that efficiency is remarkably flat over the load range. At loads from 30% to 107% MCR, efficiency varies by less than 1%. The differences in efficiency with and without FGR must be regarded as negligible. They could easily be changed by minor adjustments in excess air level.

Table 3 and Fig. 3 show NO_x emissions using natural gas and FGR well below the limit of 22 ng/J over the load range except at full load, when NO_x approaches the allowable limit. Indeed, at 50% MCR or less, NO_x emissions are only slightly more than half the allowable level. Without FGR, NO_x levels are approximately twice as high, and the allowable limit is exceeded at all loads. Clearly, for natural gas firing, flue gas recirculation is very effective in reducing NO_x.

Conversely, FGR nearly doubles CO emissions as shown in Table 3 and Fig. 4. However, even the highest value, 6 ng/J at 107% MCR, is insignificant compared with the limit of 125 ng/J in the proposed standard.

Emissions of SO_2 for natural gas firing are not reported since they were generally below the detection limit of the SO_2 analyzer. Indeed, since natural gas is generally viewed as a sulphur-free fuel, the proposed standard does not include an SO_2 emission limit for natural gas firing.

RESULTS WITH NO. 2 FUEL OIL

Table 4 gives averaged data for the tests using No. 2 fuel oil. Boiler efficiency and emissions data are given in Table 5 and Fig. 5 to 8.

Boiler efficiency was 2 to 3% higher for No. 2 oil than for natural gas. Figures 2 and 5 can be compared directly, since both show efficiency as determined by the indirect method. Fuel oil enjoys an advantage of about 4% in the loss due to combustion of hydrogen because of its lower hydrogen content. On the other hand, the dry flue gas loss in the oil-fired tests was 1 to 2% higher than in the gas-fired tests mainly because of higher excess air levels. In Test 11, excess air was unusually low and the efficiency was correspondingly high at 84.4%. This demonstrates that the burner can achieve low excess air using both No. 2 oil and natural gas. However, to ensure smoke-free combustion under fluctuating load conditions, automatic controls are usually adjusted to provide a higher level of excess air when firing oil than when firing natural gas. Flue gas recirculation seems to have no effect on boiler efficiency.

Figure 6 shows NO_x emissions. With FGR they meet the proposed limits of 43 ng/J at loads below 40% MCR, rise to nearly 50 ng/J at 55% MCR, and drop back to a little more than the allowable limit at full load. However, without FGR NO_x emissions are 20 to 25% higher and meet the proposed limits only at minimum load. In the mid-load range NO_x emissions are about 20 % over the

limit, and at full load, 40% over the limit. It is worth noting that in Test No. 11, in which excess air level was unusually low, the NO_x level is lower than might be expected from the curve in Fig. 6. This concurs with preliminary data from the other FIBEC test site at CFB Dockyard, Halifax, where reducing excess air was found to achieve a modest reduction in NO_x.
Figure 7 indicates no effect of FGR on CO emissions and similar to natural gas firing, CO emissions are always well below the limit of 125 ng/J.

Conversely, SO_2 emissions are always five to six times the 25 ng/J allowable limit. Figure 8 shows, as would be expected, no effect due to FGR. While one would not expect fuel oil drawn from the same tank to vary by $\pm$25% from the mean value of sulphur content, there appears to be no other plausible explanation for the low SO_2 values for Test 7 and the high values for Test 11.

CONCLUSIONS

1. When firing natural gas with FGR, the combustion system retrofitted to Boiler No. 4 in the central heating plant at CFB St. Hubert meets the requirements, with respect to NO_x and CO, of Environment Canada's draft regulations for emissions from boilers at federal facilities.

2. When firing No. 2 oil with FGR, NO_x emissions slightly exceed the proposed limits at loads above 40% MCR. Without FGR, NO_x emissions meet the proposed limit only at minimum load. At higher loads the limit is exceeded by 20 to 40%.

3. When firing natural gas, flue gas recirculation reduced NO_x emissions by about 50%. When firing No. 2 oil, flue gas recirculation reduced NO_x emissions by about 20%.

4. For both fuels, CO emissions were insignificant at less than 10 ng/J compared with the allowable limit of 125 ng/J.

5. When firing No. 2 oil, SO_2 emissions were typically five to six times higher than the allowable limit of 25 ng/J. The selected combustion technology cannot be expected to reduce SO_2 emissions; the only means for achieving compliance is to purchase fuel with a sulphur content less than 0.05%. For No. 2 fuel oil, this may prove to be difficult and very expensive.

6. For both fuels, boiler efficiency was higher than might be expected from a boiler without secondary heat recovery. This was in part due to good control of excess air level by the burner, but it also indicates that the heat exchange surfaces have been kept clean.

ACKNOWLEDGEMENTS

Thanks to the cooperation of the plant superintendent, Mr. G. Dube, and the plant operating staff, the entire test program proceeded smoothly and efficiently. The assistance and coordination rendered by Maj. J. Critchley, Mr. S. Brownlee and Mr. C. Lees of National Defence Canada and Mr. J. Hayes of EMR is also acknowledged.

Table 1 Analytical data for test fuels

Component Analysis - Natural Gas

Component	Mol %
Nitrogen (N_2)	1.87
Carbon Dioxide (CO_2)	0.43
Methane (CH_4)	95.98
Ethane (C_2H_6)	1.62
Propane (C_3H_8)	0.08
Iso-butane (C_4H_{10})	0.01
N-butane (C_4H_{10})	0.01
Total	100.00

Ultimate Analysis, wt %

Component	Natural Gas	Oil
Carbon (C)	72.1	86.5
Hydrogen (H_2)	23.9	13.2
Sulphur (S)	- - - -	0.3
Nitrogen (N_2)	3.2	- - - -
Oxygen (O_2)	0.8	- - - -
Ash	- - - -	- - - -
Total	100.00	100.00
Specific gravity	0.576 (rel. to air)	0.8654 (rel. to water)
Higher heating value	52.14 MJ/kg 987.3 Btu/ft.^{3}*	45.24 MJ/kg 19,450 Btu/lb

* Measured value at 14.73 psia and 60 ^{o}F

Table 2 Average raw data for natural gas firing

Test No.	1	2	3	4	13	14	15
FGR - (on / off)	on	on	on	on	off	off	off
Steam out, 10^3lb/h	5.7	10.5	15.1	26.8	7.6	16.7	25.5
Steam, psig	95.7	99.3	97	102.6	100.0	103.3	102.6
Feedwater, psig	143.7	143.2	149.2	144.0	140.0	139.6	138.6
Feedwater, °C	108.7	107.2	106.7	107.2	106.7	106.7	106.7
Fuel flow,scfh	6997	12,015	17,050	29,510	12,015	19,490	29,510
Furnace draft,in.H2O	0.11	0.10	0.15	0.12	0.10	0.10	0. 09
Outlet draft,in.H2O	0.18	0.18	0.25	0.34	0.15	0.20	0.28
Burner air pressure-in. H_2O	1.5	4.3	8.5	15.5	1.6	11.2	15.0
Stack temp., °C	166	178.8	189.7	224.6	168.1	191.2	212.7
Comb. air temp.,°C	22.6	20.0	22.0	23.3	21.0	21.5	24.6
FGR temp.,°C	102	116	133	166	n/a	n/a	n/a
Flue Gas Analysis							
O_2, %	5.97	3.14	3.11	2.12	3.32	3.26	2.14
CO_2, %	8.07	9.47	9.46	10.02	9.54	9.57	10.10
CO, ppm measured	18	20	20	23	12	12	15
NO_x, ppm measured	20	24	28	43	47	81	84
Excess air, %	35	16	16	9.5	16.5	16.5	9.5

Table 3 Boiler efficiency and emissions for natural gas firing

Test No.	1	2	3	4	13	14	15
FGR - (on / off)	on	on	on	on	off	off	off
Steam out, % MCR	22.7	42.1	60.6	107.0	30.4	66.8	102.0
Heat abs.,10^6Btu/h	5.65	10.48	15.09	26.67	---	---	---
Heat in.,10^6Btu/h	6.91	11.86	16.83	29.14	---	---	---
Excess air[1], %	35.0	16.0	16.0	9.5	16.5	16.5	9.5
Dry flue gas[2] lb/lb fuel fired	21.99	18.80	18.82	17.80	18.68	18,62	17.67
Efficiency, direct,%	81.80	88.35	89.66	91.52	---	---	---
Indirect Efficiency							
Dry gas loss[2],%	6.07	5.75	6.08	6.9	5.29	6.09	6.40
Hydrogen loss[2],%	11.21	11.36	11.41	11.67	11.26	11.43	11.55
Rad./conv. loss[3],%	4.05	2.37	1.70	1.05	3.12	2.20	1.10
Unmeasured loss[4],%	0.25	0.25	0.25	0.25	0.25	0.25	0.25
Total losses,%	21.58	19.73	19.44	19.87	19.92	19.97	19.30
Efficiency	78.42	80.27	80.56	80.13	80.08	80.03	80.70
Emissions							
CO, ppm at 3%O_2	22	20	20	22	12	12	14
CO, ng/J	6.9	6.4	6.4	7.0	3.9	3.9	4.6
NO_x, ppm at 3%O_2	29	24	28	41	48	82	80
NO_x, ng/J	12.6	12.7	14.8	21.4	25.1	43.1	42.0

1. Calculated from O_2
2. ASME test procedure
3. From Fig. 1
4. Assumed value

Table 4 Average Raw Data for No. 2 Oil Firing

Test No.	5	6	7	8	9	10	11	12
FGR - (on / off)	on	on	on	on	off	off	off	off
Steam output, 10^3 lb/h	26.8	13.8	9.2	6.6	9.6	6.6	18.0	25.2
Steam pressure, psig	100.8	98.9	99.8	99.2	101.2	98.9	101.7	101.7
Feedwater, psig	140.7	147.1	148.6	151.3	151.2	138.2	160.8	140.0
Feedwater, °C	107.4	107.2	107.2	107.2	107.1	107.2	107.2	106.9
Oil pressure, psig	405	385	400	370	390	380	400	400
Oil temp., °C	9	8	10	- -	- -	- -	- -	- -
Furnace draft., in. H_2O	0.11	0.15	0.13	0.12	0.13	0.09	0.09	0.11
Outlet draft, in. H_2O	0.35	0.25	0.22	0.20	0.20	0.15	0.2	0.3
Burner air pressure in. H_2O	14.5	8.0	4.8	3.0	5.2	2.6	11.0	14.3
Stack temp., °C	228.4	190.5	180.0	174.2	176.6	169.5	194.3	218.1
Comb. air temp., °C	26.0	25.2	24.0	23.8	23.2	21.9	20.8	21.3
FGR temp., °C	174	135	131	133	- -	- -	- -	- -
Flue Gas Analysis								
O_2, %	3.7	5.6	6.9	8.8	6.8	7.9	2.8	3.9
CO_2, %	12.4	11.1	10.1	8.9	10.1	9.2	12.6	11.9
CO, ppm measured	15	10	14	14	14	19	16	15
NO_x, ppm measured	77	77	60	43	73	56	93	103
SO_2, ppm measured	165	150	109	121	137	133	221	180
Excess air, %	19.5	33.1	45.2	65.9	43.9	55.3	14.2	21.0

Table 5 Boiler efficiency and emissions for No. 2 oil firing

Test No.	5	6	7	8	9	10	11	12
FGR - (on / off)	on	on	on	on	off	off	off	off
Steam out, % MCR	107.2	55.2	36.8	26.4	38.4	26.4	72	100.8
Heat abs.,10^6Btu/h	26.65	13.78	9.22	6.58	9.55	6.60	17.95	25.14
Excess air[1], %	19.5	33.1	45.2	65.9	43.9	55.3	14.2	21.0
Dry flue gas, lb/lb fuel fired	17.56	19.41	21.37	24.03	21.41	23.38	17.21	18.16
Indirect Efficiency								
Dry gas loss[2], %	7.89	7.13	7.40	8.03	7.29	7.67	6.63	7.94
Hydrogen loss[2], %	7.42	7.23	7.19	7.17	7.18	7.16	7.30	7.42
Rad./conv. loss[3], %	1.05	1.87	2.65	3.52	2.60	3.50	1.42	1.10
Unmeasured loss[4], %	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25
Total losses, %	16.63	16.48	17.49	18.97	17.32	18.58	15.60	16.71
Efficiency, %	83.39	83.52	82.51	81.03	82.68	81.42	84.40	83.29
Emissions								
CO, ppm at 3%O_2	16	12	18	21	18	26	16	16
CO, ng/J	5.3	3.9	6.0	6.9	5.9	8.8	5.3	5.3
NO_x,ppm at 3%O_2	80	90	77	63	93	77	92	109
NO_x, ng/J	44.3	49.8	42.4	35.2	51.3	42.6	50.9	60.0
SO_2, ppm at 3%O_2	172	175	140	179	174	183	219	190
SO_2, ng/J	132.4	135.3	107.4	138.0	134.1	141.2	168.5	146.1

1. Calculated from O_2
2. ASME test procedure
3. From Fig. 1
4. Assumed value

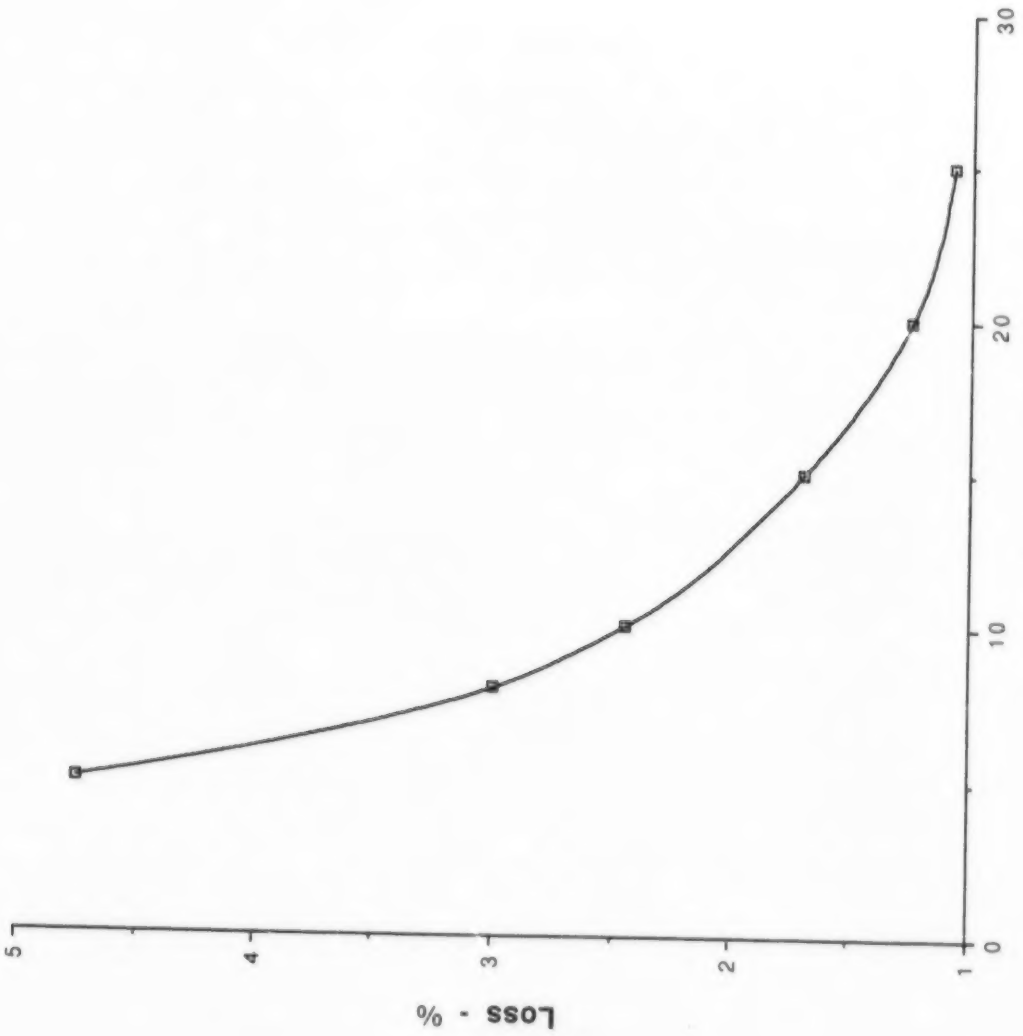

Fig. 1. Radiation and convection heat loss

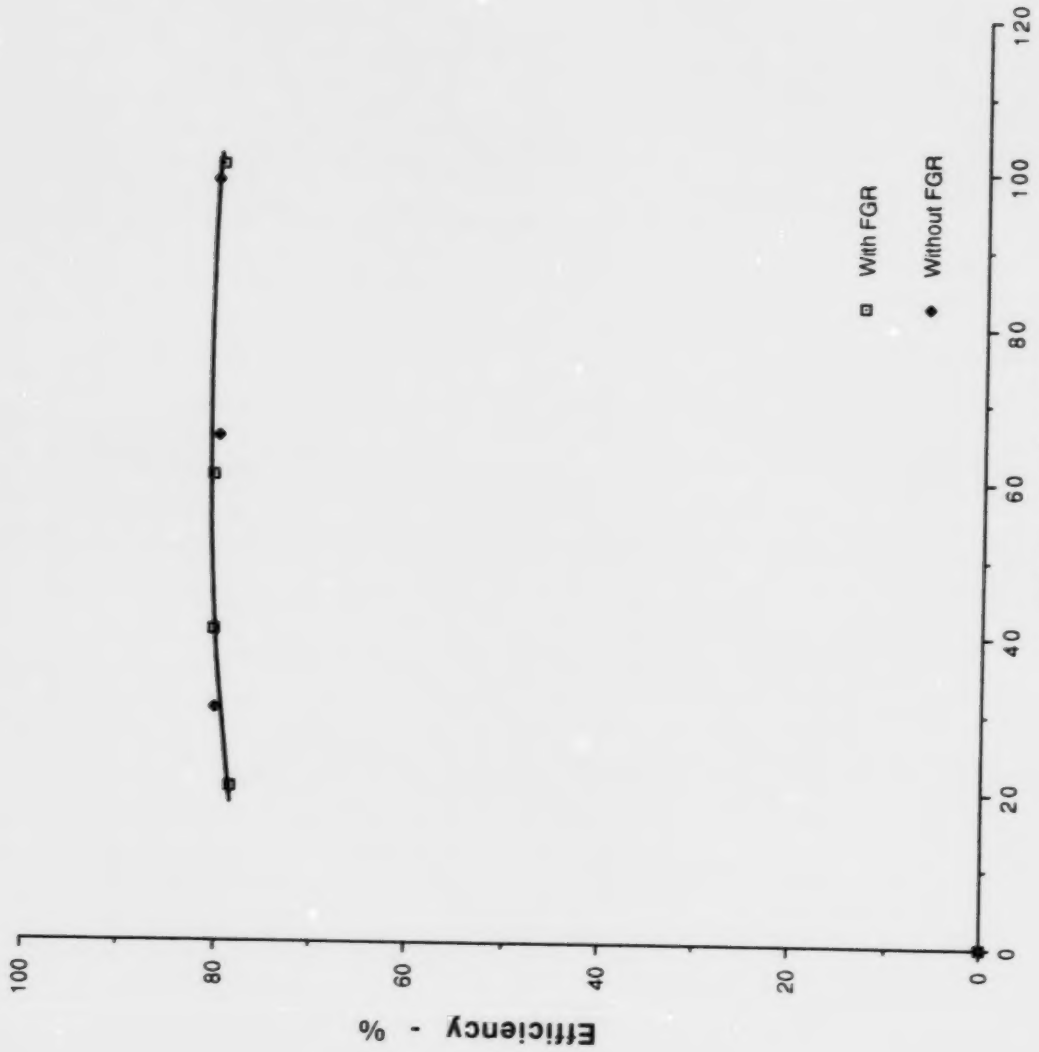

Fig. 2. Boiler efficiency with natural gas

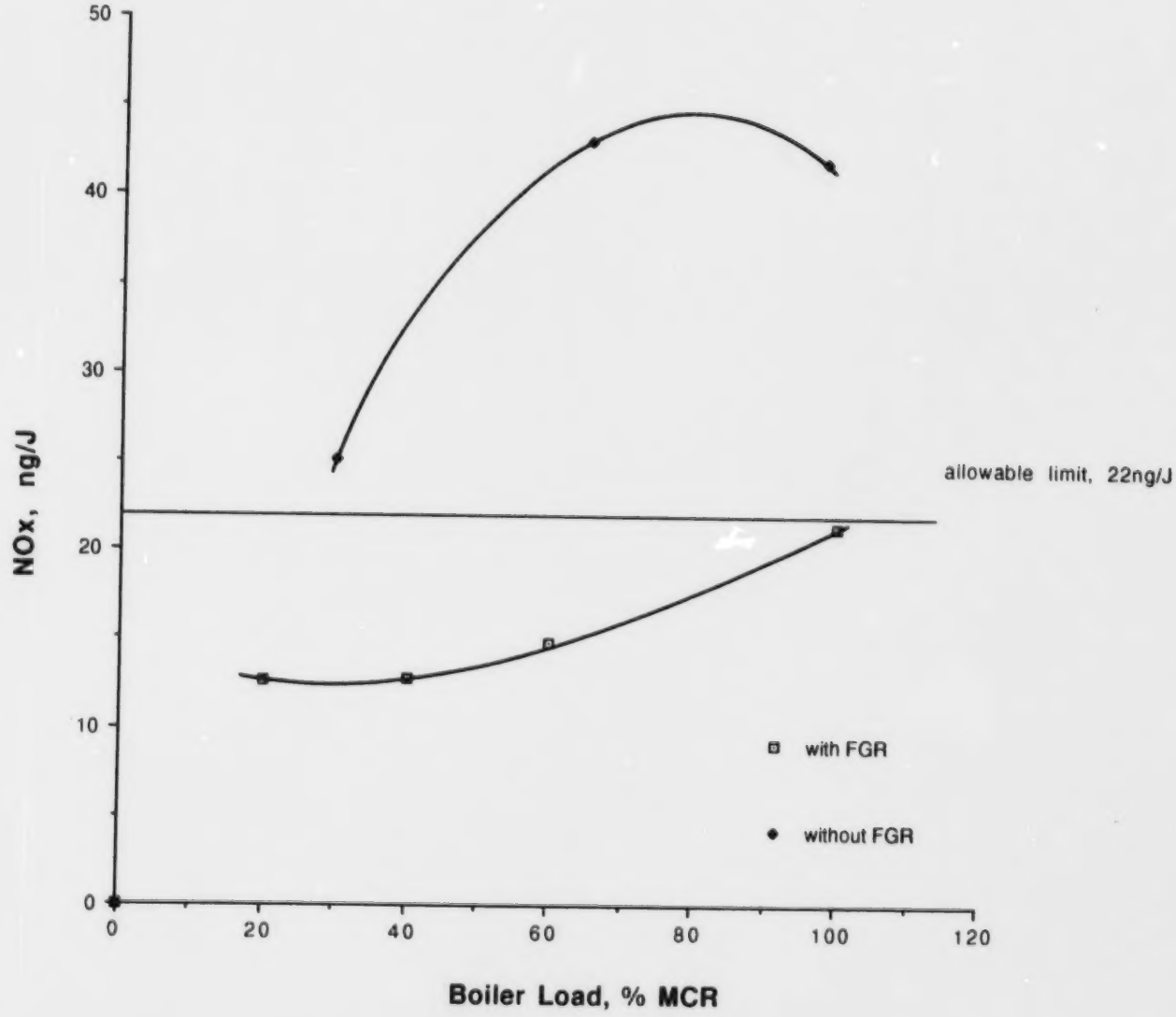

Fig. 3. NOx emissions with natural gas

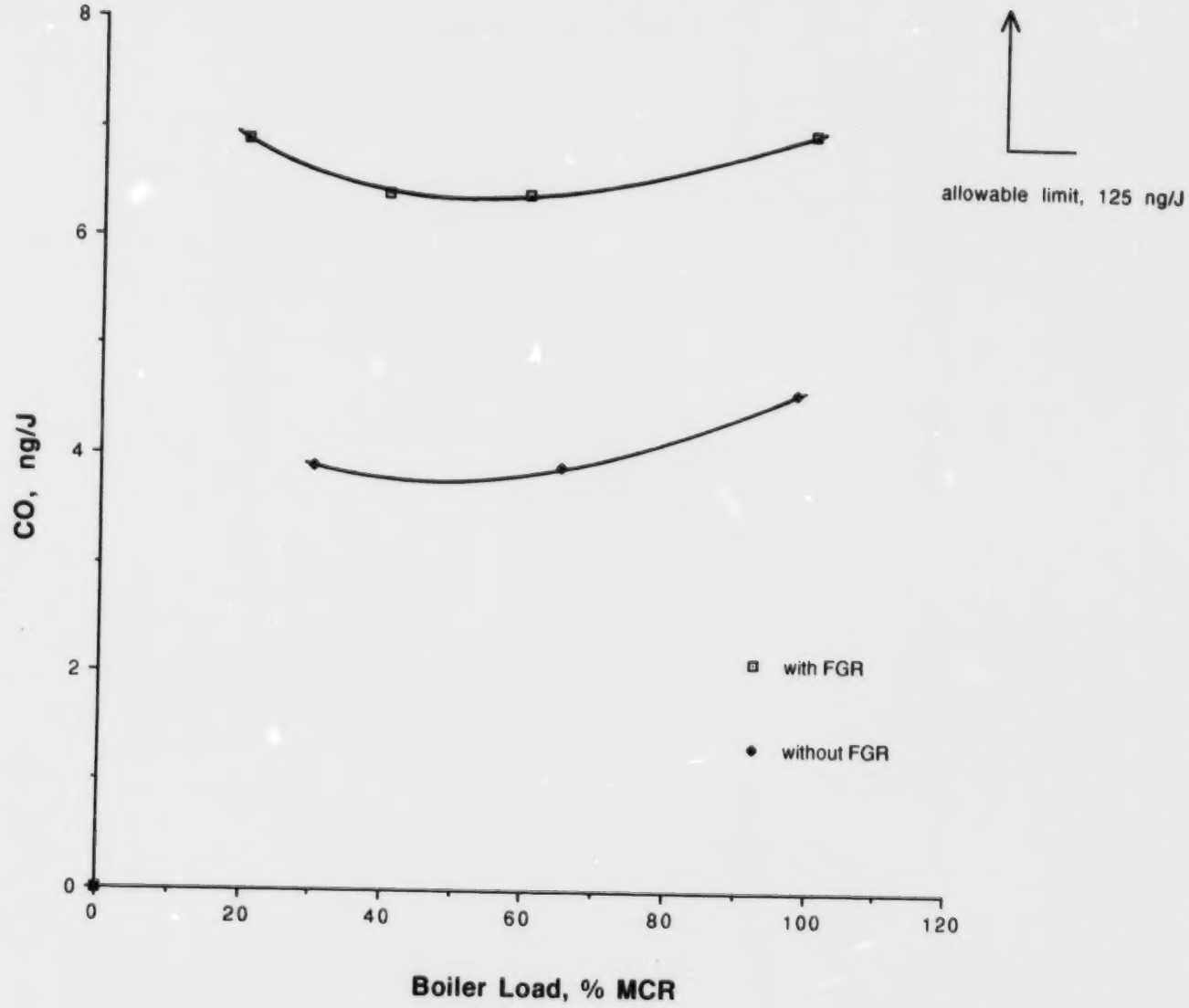

Fig. 4. CO emissions with natural gas

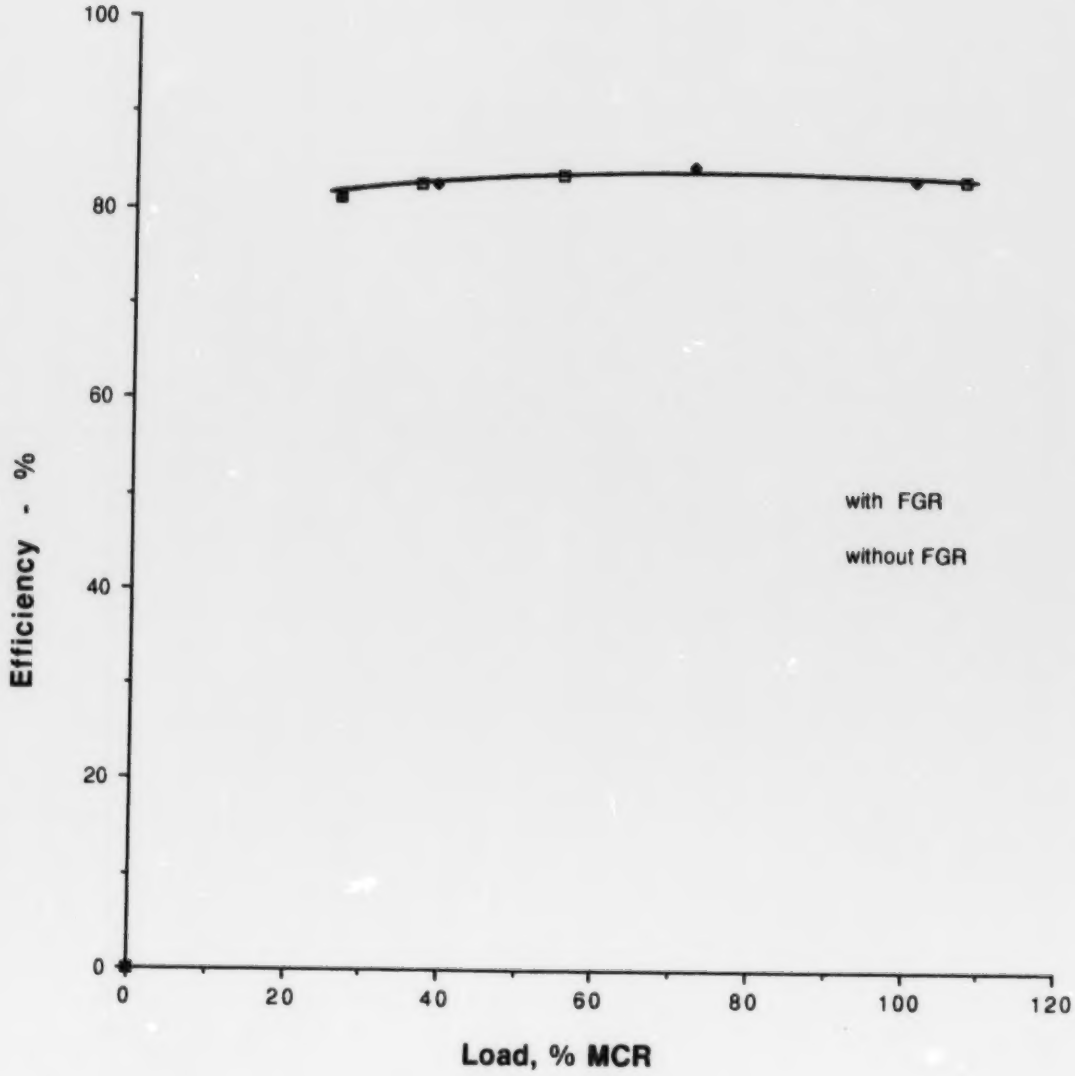

Fig. 5. Boiler efficiency with No. 2 oil firing

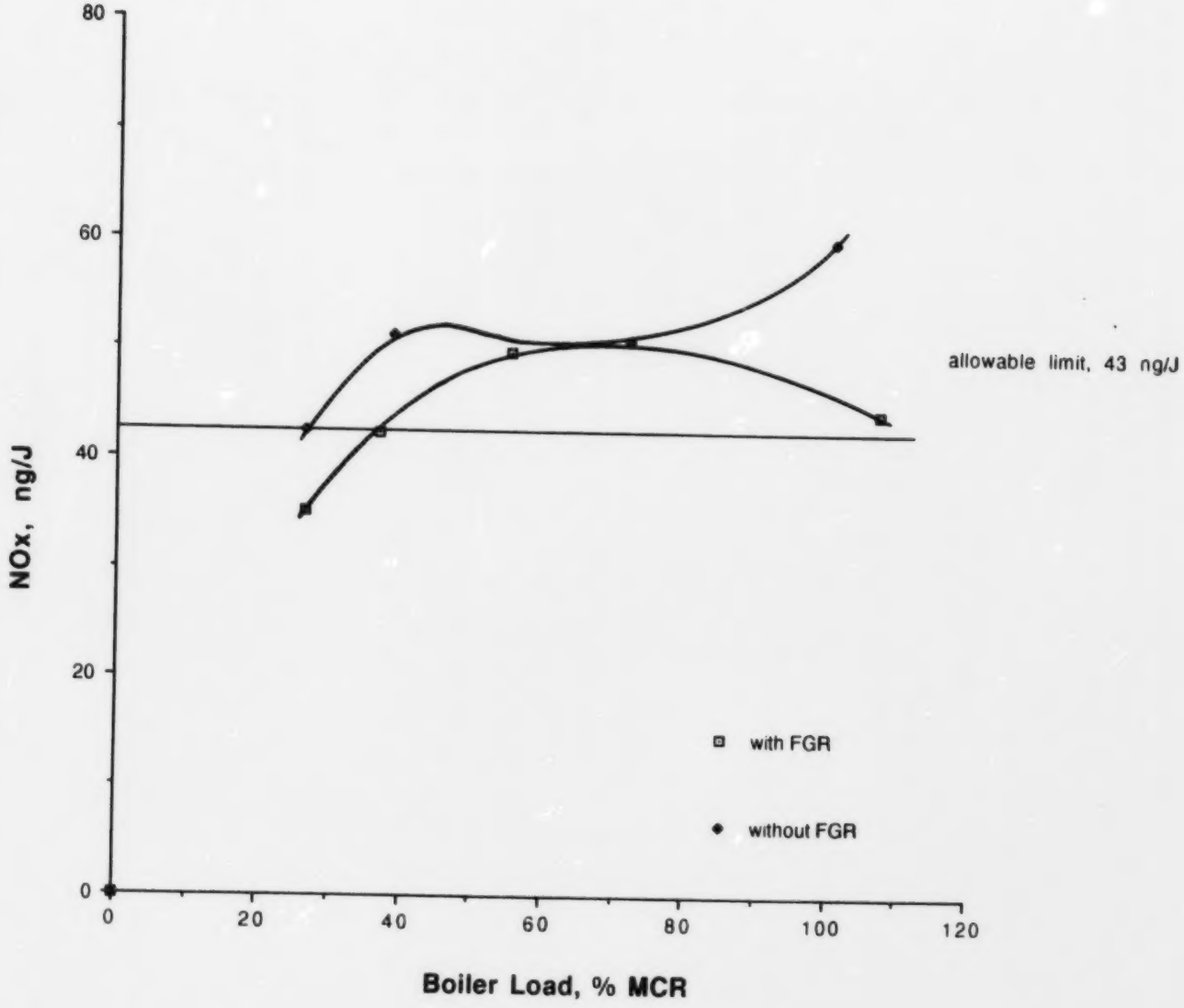

Fig. 6. NOx emissions with No. 2 oil firing

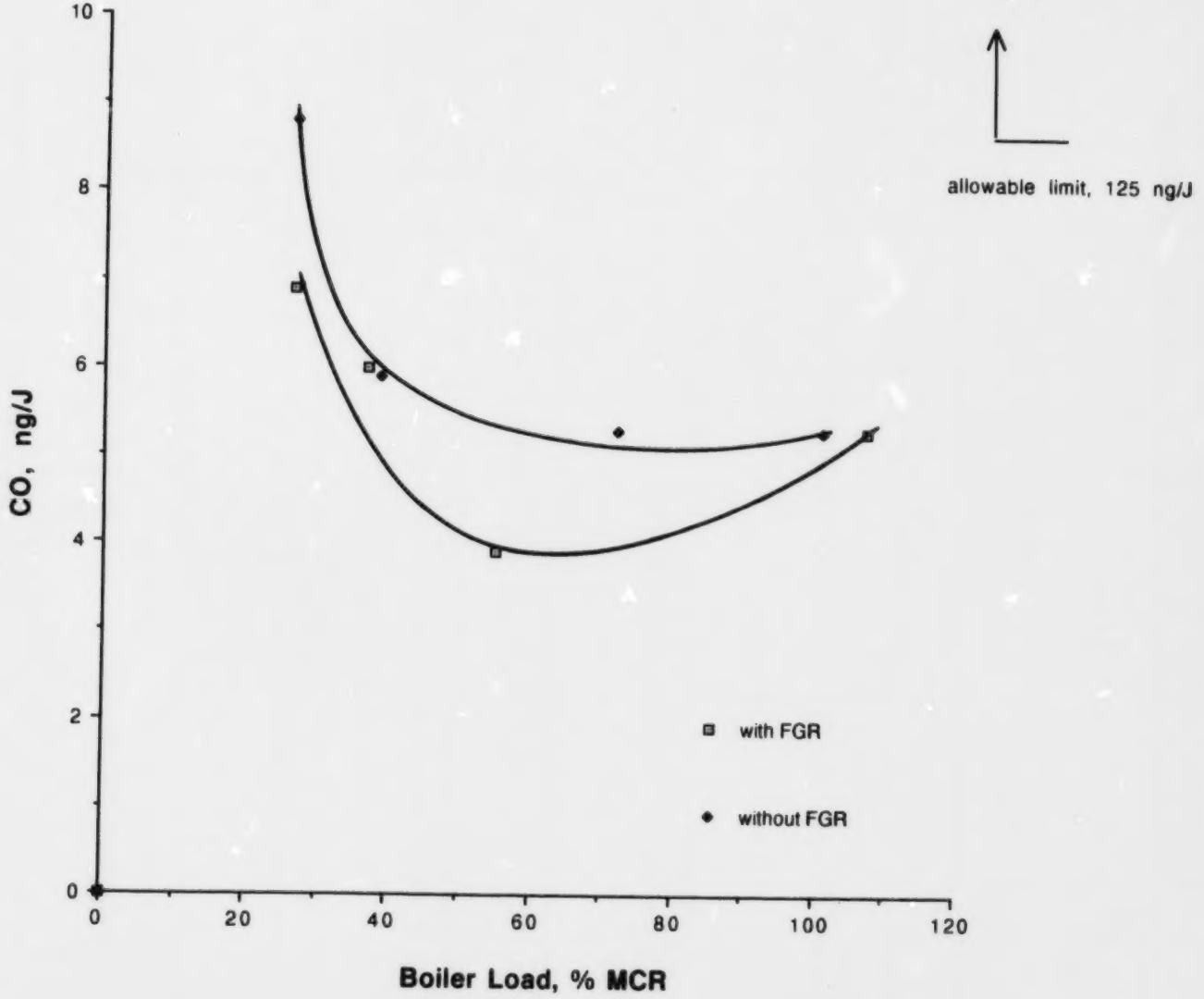

Fig. 7. CO emissions with No. 2 oil firing

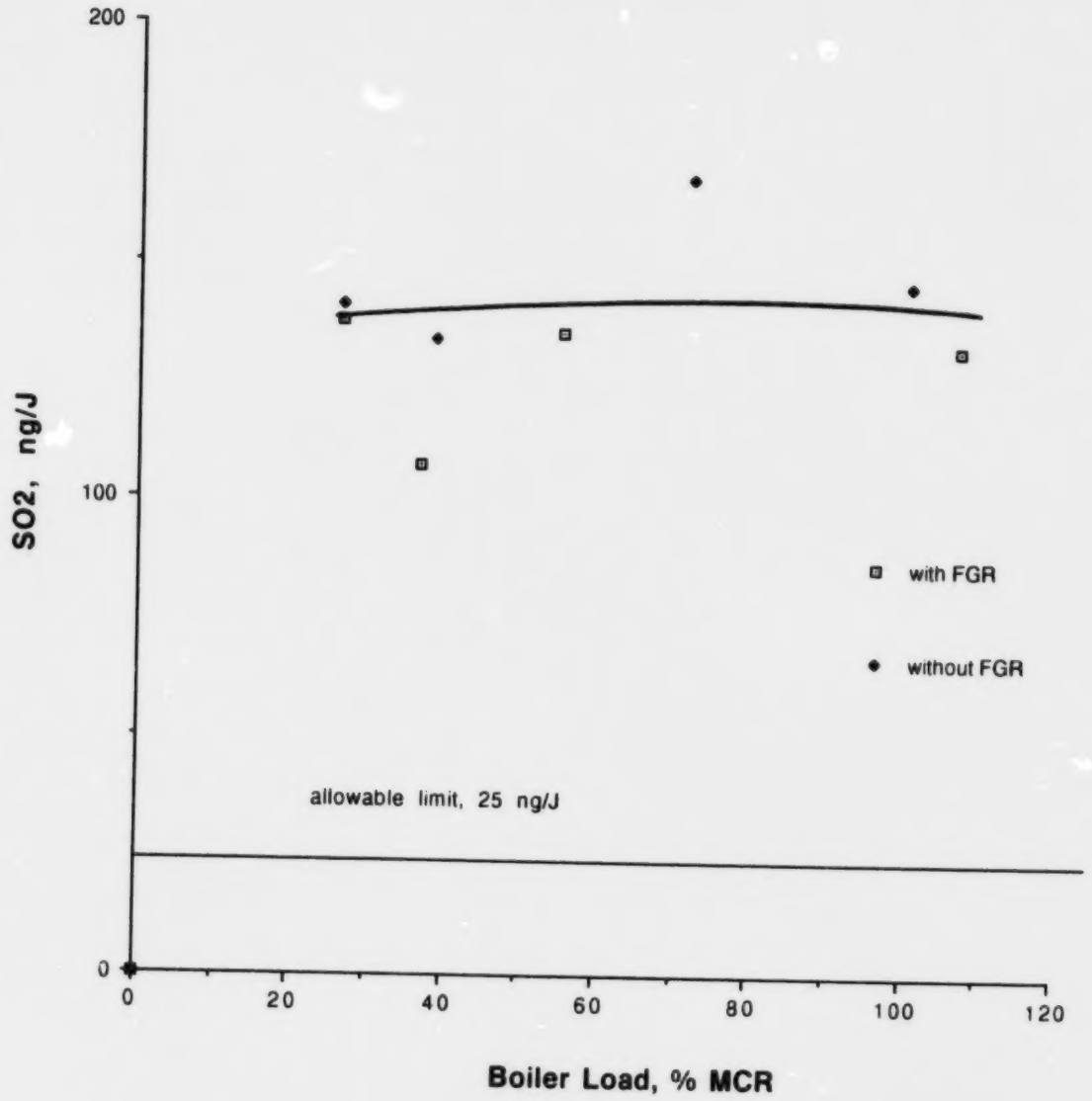

Fig. 8. SO2 emissions with No. 2 oil firing

APPENDIX I

REGULATIONS RESPECTING RELEASE INTO THE AMBIENT AIR OF EMISSIONS FROM BOILERS AT FEDERAL FACILITIES*

Short Title

1. These Regulations may be cited as the Federal Boiler Emission Regulations.

Interpretation

2. In these Regulations,

"boiler" means a device that burns fossil fuel for the purpose of generating hot water or steam and is used primarily for the heating of buildings: (chaudiere)

"new boiler" means a boiler for which a contract to purchase is signed on or after April 1, 1991; (chaudiere existante)

"federal institution" means a department, board or agency of the Government of Canada, or any corporation that is named in Schedule III to the Financial Administration Act; (institution federale)

"fossil fuel" means natural gas, petroleum, coal, and any form of gaseous, liquid or solid fuel derived from such for the purpose of creating useful heat; (combustible fossile)

"MJ/s" means megajoules per second; (MJ/s)

"mg/m^3" means milligram per cubic metre on a dry basis at 298 K and 101.3 kPa; (mg/m^3)

"ng/J" means nanograms per joule; (ng/J)

* Draft; October 1990

"solid fossil fuel" means coal, or any combination of fuels for which coal is the primary source of usable energy; (combustible fossile solide)
"gaseous fossil fuel" means natural gas or propane or any fuel in the gaseous state derived from natural gas or propane; (combustible fossile gazeux)

"nitrogen oxides" means all oxides of nitrogen except nitrous oxide, collectively expressed as nitrogen dioxide; (oxydes d'azote)

"undiluted" means in a condition that does not include air or other gases in excess of the quantity necessary for the normal operating requirement of the boiler; (non-dilue)

"smoke density" means the smoke density of a flue gas determined in accordance with the American Society for Testing and Materials (ASTM) designation D 2156-80, reapproved 1988; (densite de la fumee)

"CGSB classification" means the classification of fuel types specified in "National Standard of Canada CAN2-3.2-M81 Fuel Oil, Heating" published by the Canadian General Standards Board, as amended from time to time. (classification de l'ONGC)

Application

3. These Regulations apply in respect of facilities owned or operated by a federal institution.

Duty of Federal Institutions

4. Where a boiler is operated under contract with a federal institution, the federal institution shall ensure that the person who operates the boiler complies with sections 5 to 13.

Prohibition

5. No person shall operate a boiler except in accordance with sections 6 to 13.

Emissions Standards for New Boilers

6. The rate of discharge of air contaminants from a new boiler having a heat input capacity greater than 1.5 MJ/s and less than 50 MJ/s shall not exceed:

a) for nitrogen oxides expressed as nitrogen dioxide:

i) 150 ng/J of heat input when fired with solid fossil fuel,

ii) 110 ng/J of heat input when fired with oil specified as type 4, 5 or 6, according to CGSB classification,

iii) 43 ng/J of heat input when fired with oil specified as type 1 or 2, according to CGSB classification, and

iv) 22 ng/J of heat input when fired with gaseous fuel;

b) for sulphur dioxide:

i) 500 ng/J of heat input when fired with solid fossil fuel,

ii) 500 ng/J of heat input when fired with oil specified as type 4, 5 or 6, according to CGSB classification, and

iii) 25 ng/J of heat input when fired with oil specified as type 1 or 2, according to CGSB classification;

c) for particulate matter measured undiluted, 160 mg/m^3, when fired with solid fossil fuel; and

d) for carbon monoxide, 125 ng/J of heat input.

Emissions Standards for Existing Boilers

7. 1) Subject to Section 9, effective April 1, 1997, the rate of discharge of nitrogen oxides, expressed as nitrogen dioxide, from an existing boiler having a heat input capacity greater than 5.9 MJ/s and less than 50 MJ/s, shall not exceed

a) 150 ng/J of heat input when fired with solid fossil fuel

b) 110 ng/J of heat input when fired with oil specified as type 4, 5 or 6, according to CGSB classification

c) 43 ng/J of heat input when fired with oil specified as type 1 or 2, according to CGSB classification, and

d) 22 ng/J of heat input when fired with gaseous fuel.

2) Effective April 1, 1994, the rate of discharge of air contaminants from an existing boiler having a heat input capacity greater than 5.9 MJ/s and less than 50 MJ/s shall not exceed

a) for sulphur dioxide;

i) 500 ng/J of heat input when fired with solid fossil fuel,

ii) 500 ng/J of heat input when fired with oil specified as type 4, 5 or 6, according to CGSB classification, and

iii) 25 ng/J of heat input when fired with oil specified as type 1 or 2, according to CGSB classification;

b) for particulate matter measured undiluted, 160 mg/m^3, when fired with solid fossil fuel;

c) for carbon monoxide, 125 ng/J of heat input.

3) Subsection (1) does not apply to an existing boiler that is part of a facility described in column I of an item of Schedule I or II, where notice is received by the Minister pursuant to subsection 9 (1) or (3).

Revision of Base Year NO_x Emission

8. 1) For the purposes of this section and section 9

a) "base year NO_x emission" of nitrogen oxides means for

i) a facility listed in column I of an item of Schedule I, the total emission, in tonnes, set out in column III of the item, and

ii) a facility listed in column I of an item of Schedule II, the total emission, in tonnes, set out in column III of that item;

b) "responsible federal department or institution" means, with respect to a facility, the federal department or institution specified in column II of an item of Schedule I or II, for the facility specified in column I of that item.

2) Where the responsible federal department or institution requests that the Minister review the base year NO_x emission for a facility, the Minister shall review the base year NO_x emission based on information provided pursuant to the subsection (3)

3) Where a federal department or institution makes a request with respect to a facility pursuant to subsection (2), the department or institution shall provide the Minister, prior to June 1 of any year, with the information required pursuant to Schedules IV and V for the period from April 1 of the preceding year to March 31 of that year for that facility.

4) The Minister shall revise the base year NO_x emission for a facility where he is satisfied that such a revision is justified based on the information provided pursuant to subsection (3) and any other information relevant to the control of emissions from that facility.

Reduction of Total Emissions From Existing Boiler Facilities

9. 1) Where an existing boiler having a heat input capacity greater than 5.9 MJ/s and less than 50 MJ/s is part of a facility described in column I of an item of Schedule I, the responsible federal department or institution shall, after giving written notice to the Minister prior to June 1, 1994, reduce nitrogen oxides emissions from all boilers comprising the facility, in accordance with subsection (2).

2) For the purposes of subsection (1), emissions of nitrogen oxides from all boilers comprising the facility shall be reduced by:

a) in the twelve month period commencing April 1, 1995 and ending March 31, 1996, for a facility referred to in Column I of an item of Schedule I, 25 percent of the amount set out in Column III of that item and,

b) in the twelve month period commencing April 1, 1997 and ending March 31, 1998, and in any subsequent twelve month period commencing April 1 and ending March 31, for a facility referred to in Column I of an item of Schedule I, 50 percent of the amount set out in Column III of that item.

3) Where an existing boiler having a heat input capacity greater than 5.9 MJ/s and less than 50 MJ/s is part of a facility described in column I of an item of Schedule II, the responsible federal department or institution shall, after giving written notice to the Minister prior to June 1, 1994, reduce nitrogen oxides emissions from all boilers comprising the facility, in accordance with subsection (4)

4) For the purposes of subsection (3) emissions of nitrogen oxides from all boilers comprising the facility shall be reduced by:

a) in the twelve month period commencing April 1, 1995 and ending March 31, 1996, for a facility referred to in Column I of an item of Schedule II, fifteen percent of the amount set out in Column III of that item; and,

b) in the twelve month period commencing April 1, 1997 and ending March 31, 1998, and in any subsequent twelve month period commencing April 1 and ending March 31, for a facility referred to in Column I of an item of Schedule II, thirty percent of the amount set out in Column III of that item.

5) For the purposes of subsections (2) and (4) emissions of nitrogen oxides for any twelve moth period shall be determined in accordance with Schedule V.

Smoke Density

10. A new boiler having a heat input capacity greater than 1.5 MJ/s and less than 50 MJ/s, and an existing boiler having a heat input capacity greater than 5.9 MJ/s and less than 50 MJ/s shall be operated in such a manner that the smoke density of the flue gases does not exceed

a) a smoke spot number of 5, when fired with oil specified as type 4, 5 or 6, according to CGSB classification; and

b) a smoke spot number of 3, when fired with oil specified as type 1 or 2, according to CGSB classification.

Emissions Testing

11. 1) For the purposes of sections 5 to 10, emissions testing shall be conducted by the operator at least once per year on the date and at the location specified in a written notice received by the Minister no less than 30 days in advance of the day on which the testing is to be conducted.

2) The notice referred to in subsection (1) shall specify the reference methods and test procedures to be used.

3) Where requested by the Minister, emissions testing shall be conducted in the presence of an inspector.

4) An emissions test required under subsection (1) shall be conducted using the following test methods:

a) for nitrogen oxides the reference method specified in the Department of the Environment Report EPS 1/RM/15, "Reference Method for the Monitoring of Gaseous Emissions from Fossil-Fuel Fired Boilers", as amended from time to time;

b) for particulate matter, the reference method specified in the Department of the Environment Report EPS 1-AP-74-1, "Standard Reference Methods for Source Testing: Measurement of Emissions of Particulates from Stationary Sources", as amended from time to time;

c) for sulphur dioxide, the reference method specified in the Department of the Environment Report EPS 1/RM/15, "Reference Method for the Monitoring of Gaseous Emissions from Fossil-fuel Fired Boilers", as amended from time to time;

d) for carbon monoxide, the reference method specified in the Department of the Environment Report EPS 1/RM/15, "Reference Method for the Monitoring of Gaseous Emissions from Fossil-Fuel Fired Boilers", as amended from time to time; and

e) for smoke density, in accordance with the American Society for Testing and Materials (ASTM) Designation D 2156-80, reapproved 1988.

5) Emissions testing required pursuant to subsection (1) shall consist of

a) one test conducted during operation of the boiler between thirty percent and forty percent of maximum rated capacity; and

b) one test conducted during operation of the boiler between sixty percent and seventy percent of maximum rated capacity.

6) The rate of discharge of an air contaminant is the arithmetic mean of the test results referred to in paragraphs 5 (a) and (b).

Notice

12. Where a new boiler having a heat input capacity greater than 1.5 MJ/s and less than 50 MJ/s commences operation the owner or operator of the facility where the boiler is located shall, within 60 days of the boiler commencing operation, notify the Minister in writing of the date of commencement of the operation, the location, and heat input capacity of the boiler.

Reporting

13. 1) A report on the results of any tests conducted pursuant to section 11 shall be submitted to the Minister in writing in the format set out in Schedule III no later than sixty days after the day on which the test was completed.

2.) For the purposes of section 9, a responsible federal institution or Department set out in column II of an item of Schedule I or II, shall submit to the Minister, no later than June 1 of each year, in the form set out in schedules IV and V for each facility set out in column I of that item

a) a report indicating total NO_x emissions for the preceding period of April 1 to March 31; and

b) such further information as the Minister requests.